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13,177,510

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9,024,646

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13,260,202

$

11,569,718

Distributable Income

$

12,019,847

$

10,947,816

$

7,808,725

$

11,268,383

$ 9,776,735

Distribution Amount

$ 11,919,847

$ 10,732,816

$ 7,808,725

$ 11,268,383

$ 9,776,735

Distributable Income per unit

$

2.04

$

1.86

$

1.32

$

1.91

$

1.66

Distribution Amount per unit

$

2.02

$

1.82

$

1.32

$

1.91

$

1.66

Total assets at year end

$

35,000,087

$	37,436,640
$	41,006,654
$	45,129,170
$	50,964,669

Item 7. ***Management s Discussion and Analysis of Financial Condition and Results of Operations*****.**

General

The Trust does not conduct any operations or activities. The Trust s purpose is, in general, to hold the Net Profits Interests, to distribute to Unitholders cash which the Trust receives in respect of the Net Profits Interests and to perform certain administrative functions in respect of the Net Profits Interests and the Depositary Units. The Trust derives substantially all of its income and cash flows from the Net Profits Interests.

Under the Gas Purchase Contract, Eastern Marketing purchases gas from the Trust at a variable price for any quarter equal to the Henry Hub Average Spot Price (as defined) per MMBtu plus $0.30 per MMBtu, multiplied by 110% to effect a fixed adjustment for Btu content. The Henry Hub Average Spot Price is defined as the price per MMBtu determined for any calendar quarter equal to the price obtained with respect to each of the three months in such quarter, in the manner specified below, and then taking the average of the prices determined for each of such three months. The price determined for any month of such quarter is equal to the average of (i) the final settlement price per MMBtu for Henry Hub Gas Futures Contracts (as defined), as reported in *The Wall Street Journal*, for such contracts which expired in each of the five months prior to such month, (ii) the final settlement price per MMBtu for Henry Hub Gas Futures Contracts, as reported in *The Wall Street Journal*, for such contracts which expire during such month and (iii) the closing settlement price per MMBtu of Henry Hub Gas Futures Contracts determined as of the contract settlement date for such month, as reported in *The Wall Street Journal*, for such contracts which expire in each of the six months following such month. A Henry Hub Gas Futures Contract is defined as a gas futures contract for gas to be delivered to the Henry Hub which is traded on the New York Mercantile Exchange.

Accordingly, the price payable to the Trust for production may vary based on fluctuations in natural gas futures prices during the relevant calculation period. The price payable to the Trust will have a direct impact, positively or negatively, on the quarterly distributions payable by the Trust to the Unitholders.

During 2002, Eastern American was asked to sell 3 wells in which the Trust owned a Net Profits Interest (the Western Pocahontas #7, #8 and #10 wells). The party seeking to purchase the wells owned the right to mine for coal on such properties (the Coal Lessee). The Coal Lessee stated that the wells would materially interfere with the Coal Lessee s proposed mining operations.

Eastern American reviewed the Trust Agreement and production from these wells, and determined that the Net Profits Interest associated with the Western Pocahontas # 7 well accounted for more than 0.25% of the total production from the Underlying Properties for the prior twelve (12) month period. Eastern American advised the Coal Lessee that it could not sell this well.

Subsequently, the Coal Lessee asserted that the coal estate in the relevant Underlying Properties was the dominate estate and that under the relevant oil and gas leases and applicable case law, the Coal Lessee could cause the Trust and Eastern American to plug and abandon the well. Eastern American and the Trust did not necessarily agree with the Coal Lessee position, however, and in an effort to avoid litigation, the Trust and Eastern American entered into a Settlement Agreement and Release of All Claims with the Coal Lessee pursuant to which Eastern agreed to sell the Western Pocahontas # 7 well for the amount of $426,187. The Trust s share of the proceeds of $303,438 was included in Distributable Income to the Trust during the year ended December 31, 2002. The Coal Lessee purchased the two additional wells, the Western Pocahontas # 8 and #10 for the amount of $209,561. The Trust s share of the proceeds of $188,605 was also included in the Distributable Income of the Trust during the year ended December 31, 2002.

During 2003, a Coal Lessee contacted Eastern American and inquired as to whether it would sell the U.S. Steel Well # 26, which is a well in which the Trust owns a Net Profits Interests. The Coal Lessee stated that the well would materially interfere with the Coal Lessee s proposed mining operations. Eastern American reviewed the Trust Agreement and production from this well to determine if it could cause the Trust to sell its Net Profits Interest in the well. Upon review, it was discovered that the Net Profits Interests associated with the U.S. Steel #26 well accounted for less than 0.25% of the total production from the Underlying Properties for the prior twelve (12) month period. Eastern American advised the Coal Lessee that it could sell this well. Eastern American received $11,437 for the sale of the U.S Steel Well #26. The Trust s share of the proceeds of $10,293 was included in the Distributable Income of the Trust during the year ended December 31, 2003.

During 2004, an oil and gas company contacted Eastern American and inquired as to whether it would sell certain assets situated in Centre County, Pennsylvania including the Horne #1, Horne #2 and Horne #15 wells (the Horne Underlying Properties), which are wells in which the Trust owns a Net Profits Interests. Eastern American reviewed the Trust Agreement and certified to the Trustee that: (i) the gross purchase price to be received by Eastern American for the sale of the Horne Underlying Properties in a single transaction or a series of related transactions was less than $500,000; (ii) the Assignee of the Horne Underlying Properties was not an Affiliate of Eastern American; (iii) the aggregate sale proceeds of $80,205 to be received by the Trust from Eastern American (the Trust s Horne Sale Proceeds) represented the fair value to the Trust for Net Profits Interests to be released by the Trustee in connection with Eastern American s sale of the Horne Underlying Properties; and (iv) the Trust s Horne Sale Proceeds plus the aggregate sale proceeds received by the Trust pursuant to Section 3.02(b)(ii) of the Trust Agreement with respect to all other Net Profits Interests previously released by the Trustee pursuant to Section 3.02(b) during the most recently completed twelve calendar months did not exceed $500,000. Eastern American advised the oil and gas company that it could sell these wells. The Trust s share of the proceeds of $80,205 was included in the Distributable Income of the Trust during the year ended December 31, 2004.

Also, during 2004, a landowner contacted Eastern American to inquire about the sale of certain wells located on the landowner s property, including the Wurst #2 well, which is a well in which the Trust owns a Net Profits Interest. Eastern certified to the Trust that, (i) the Assignee of the Wurst #2 was not an Affiliate of Eastern and, (ii) the aggregate sale proceeds to be received from all other sales of wells in which the Trust owns a Net Profits Interest and previously released by the Trust during the preceeding twelve (12) calendar months did not exceed $500,000. The Wurst #2 well was found to be uneconomic to operate and was subject to plugging and abandonment by Eastern American if not assigned to the landowner. Eastern American advised the landowner that it could assign this well. The Wurst #2 well had no value and no cash distribution was made to the Trust.

Over the remaining life of the Trust, additional wells may need to be disposed of for similar or other reasons.

The Trust is responsible for paying the Trustee s fees and all legal, accounting, engineering and stock exchange fees, printing costs and other administrative expenses incurred by or at the direction of the Trustee. The total of all Trustee fees and Trust administrative expenses for 2004 was $695,805, including the Trustee s fee of $45,000. In addition to such expenses, in 2004, the Trust paid Eastern American an overhead reimbursement of $306,592. The overhead reimbursement increases by 3.5% per year and is payable quarterly.

On December 8, 2004 the Trust announced approval by the Trust Unitholders of a proposal to elect JPMorgan Chase to serve as successor trustee of the Trust upon the effective date of the resignation of The Bank of New York as trustee of and depositary for the Trust and to amend the Trust Agreement to change the compensation of the Trustee. The resignation of The Bank of New York took effect on January 1, 2005. As successor trustee, JPMorgan Chase will receive annual compensation of $108,000, plus fees and expenses.

The costs the Trust incurs in the future will fluctuate depending primarily on the expenses the Trust incurs for professional services, particularly legal, accounting and engineering services.

Critical Accounting Policies

The following is a summary of the critical accounting policies followed by the Trust.

Basis of Accounting:

The financial statements of the Trust differ from financial statements prepared in accordance with accounting principles generally accepted in the United States of America due to the following; i) certain cash reserves may be established for contingencies which were not accrued in the financial statements; ii) amortization of the Net Profits Interests in gas properties is charged directly to Trust Corpus; and iii) the sale of the Net Profits Interests is reflected in the Statements of Distributable Income as cash proceeds to the Trust.

Net Profits Interests in Gas Properties:

The Net Profits Interests in gas properties are periodically assessed to determine whether their net capitalized cost is impaired. The Trust will determine if a writedown is necessary to its investment in the Net Profits Interests in gas properties to the extent that total capitalized costs, less accumulated amortization, exceed undiscounted future net revenues attributable to proved gas reserves of the Underlying Properties. The Trust will then provide a writedown to the extent that the net capitalized costs exceed the discounted future net revenues attributable to proved gas reserves of the Underlying Properties. Any such writedown would not reduce distributable income, although it would reduce Trust Corpus.

Amortization of the Net Profits Interests in gas properties is calculated on a units-of-production basis, whereby the Trust s cost basis in the properties is divided by total Trust proved reserves to derive an amortization rate per reserve unit. Such amortization does not reduce distributable income, rather it is charged directly to Trust Corpus. Revisions to estimated future units-of-production are treated on a prospective basis beginning on the date significant revisions are known.

The Net Profits Interest impairment test and the determination of amortization rates are dependent on estimates of proved gas reserves attributable to the Trust. Numerous uncertainties are inherent in estimating reserve volumes and values, including economic and operating conditions, and such estimates are subject to change as additional information becomes available.

Income Taxes:

Tax counsel to the Trust advised the Trust at the time of formation that, under then current tax laws, the Trust would be classified as a grantor trust for federal and state income tax purposes and, therefore, would not be subject to taxation at the Trust level. The Trust continues to be tax exempt. Accordingly, no provision for federal or state income taxes has been made. However, the opinion of tax counsel is not binding on taxing authorities.

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Liquidity and Capital Resources

The Trust has no source of liquidity or capital resources other than the distributions received from the Net Profits Interests.

In accordance with the provisions of the Conveyances, generally all revenues received by the Trust, net of Trust administrative expenses and the amount of established reserves, are distributed currently to the Unitholders.

The Trust did not have any contractual obligations as of December 31, 2004. At December 31, 2004, the Trust had accounts payable of $220,596 and distributions payable of $3,639,983.

Results of Operations

2004 Compared with 2003

The Trust s distributable income was $12,019,847 for the twelve months ended December 31, 2004 as compared to $10,947,816 for the twelve months ended December 31, 2003. This increase was due to an increase in Royalty Income for the twelve months ended December 31, 2004 ($14,449,208) as compared to the twelve months ended December 31, 2003 ($13,177,510). The increase in Royalty Income was due to an increase in the average price payable to the Trust under the Gas Purchase Contract as discussed below ($6.989 per Mcf for the twelve months ended December 31, 2004; $6.086 per Mcf for the twelve months ended December 31, 2003). This increase was offset by a decrease in production of gas attributable to the Net Profits Interests for the twelve months ended December 31, 2004 (2,068 Mmcf) as compared to the twelve months ended December 31, 2003 (2,161 Mmcf). The decline in production is primarily attributable to natural production declines and the sale of wells. Taxes on production and property were $989,430 for the twelve months ended December 31, 2004 as compared to $897,881 for the twelve months ended December 31, 2003. The increase in taxes is due directly to the increase in Royalty Income as discussed above. Trust general and administrative expenses were $1,002,397 for the twelve months ended December 31, 2004 as compared to $833,027 for the twelve months ended December 31, 2003. The increase in general and administrative expenses was due primarily to an increase in legal fees of $64,234 and $51,406 in direct expenses related to the resignation of the former trustee and the appointment of a successor trustee. The distributable income includes Cash Proceeds on Sale of Net Profits Interests of $80,205 for the period ended December 31, 2004, while $10,293 was recognized in the corresponding prior twelve months.

During the twelve months ended December 31, 2004, the Trustee added an additional $100,000 to the cash reserve balance which was established during the twelve months ended December 31, 2003 in the amount of $215,000. This reserve was established to facilitate the payment of vendor invoices on a timely basis. The establishment and subsequent increase of this reserve reduced the Distribution Amount by $100,000 or $0.0169 per unit for the twelve months ended December 31, 2004 and by $215,000 or $0.0365 per unit for the twelve months ended December 31, 2003. Amortization of Nets Profits Interests in Gas Properties was $3,818,158 for the twelve months ended December 31, 2004 as compared to $4,053,133 for the twelve months ended December 31, 2003. This decrease was primarily due to the decrease in production volumes.

The average price payable to the Trust for gas production attributable to the Net Profits Interests was $6.989 per Mcf for the twelve months ended December 31, 2004 and $6.086 per Mcf for the twelve months ended December 31, 2003. The price per Mcf was higher for the twelve months ended December 31, 2004 than for the corresponding twelve month period ended December 31, 2003 due to an increase in the average spot market price for gas delivered at the Henry Hub near Henry, Louisiana ($6.054 per Dth for the twelve months ended December 31, 2004; $5.233 per Dth for the twelve months ended December 31, 2003).

2003 Compared with 2002

The Trust s distributable income was $10,947,816 for the twelve months ended December 31, 2003 as compared to $7,808,725 for the twelve months ended December 31, 2002. This increase was due to an increase in Royalty Income for the twelve months ended December 31, 2003 ($13,177,510) as compared to the twelve months ended December 31, 2002 ($9,024,646). The increase in Royalty Income was due to an increase in the average price payable to the Trust under the Gas Purchase Contract as discussed below ($6.086 per Mcf for the twelve months ended December 31, 2003;

$3.829 per Mcf for the twelve months ended December 31, 2002). This increase was offset by a decrease in production of gas attributable to the Net Profits Interests for the twelve months ended December 31, 2003 (2,161 Mmcf) as compared to the twelve months ended December 31, 2002 (2,357 Mmcf). The decline in production is primarily attributable to natural production declines and the sale of wells. Taxes on production and property were $897,881 for the twelve months ended December 31, 2003 as compared to $613,115 for the twelve months ended December 31, 2002. The increase in taxes is due directly to the increase in Royalty Income as discussed above. Trust general and administrative expenses were $833,027 for the twelve months ended December 31, 2003 as compared to $594,921 for the twelve months ended December 31, 2002. The increase in general and administrative expenses was due primarily to an increase in legal fees of $145,269 and an $81,042 increase due to the timing of payments for tax and audit services performed as well as an increase in fees for such services. The distributable income includes Cash Proceeds on Sale of Net Profits Interests of $10,293 for the period ended December 31, 2003, while $492,043 was recognized in the corresponding prior twelve months.

During the twelve months ended December 31, 2003, the Trustee established a cash reserve in the amount of $215,000 to facilitate the payment of vendor invoices on a timely basis. No such reserve existed in the prior twelve months ended December 31, 2002. Establishing this reserve reduced distributions payable by $215,000 or $0.0365 per unit for the twelve months ended December 31, 2003. Amortization of Nets Profits Interests in Gas Properties was $4,053,133 for the twelve months ended December 31, 2003 as compared to $4,474,182 for the twelve months ended December 31, 2002. This decrease was primarily due to the decrease in production volumes.

The average price payable to the Trust for gas production attributable to the Net Profits Interests was $6.086 per Mcf for the twelve months ended December 31, 2003 and $3.829 per Mcf for the twelve months ended December 31, 2002. The price per Mcf was higher for the twelve months ended December 31, 2003 than for the corresponding twelve month period ended December 31, 2002 due to an increase in the average spot market price for gas delivered at the Henry Hub near Henry, Louisiana ($5.233 per Dth for the twelve months ended December 31, 2003; $3.181 per Dth for the twelve months ended December 31, 2002).

Off-Balance Sheet Arrangements

The Trust does not have any off-balance sheet arrangements that have or are reasonably likely to have a current or future effect on the Trust s financial condition, changes in financial condition, revenue or expenses, results of operations, liquidity, capital expenditures or capital resources that is material to investors.

Item 7A. Quantitative and Qualitative Disclosure About Market Risk

The Trust does not engage in any operations, and does not utilize market risk sensitive instruments, either for trading purposes or for other than trading purposes. As described in detail elsewhere herein, the Depositary Units consist of beneficial ownership of one unit of beneficial interest in the Trust and a $20 face amount beneficial ownership interest in a $1,000 face amount zero coupon Treasury Obligation maturing on May 15, 2013. High and low price information for the Treasury Obligations is included under Item 5. As described in detail elsewhere herein, gas production attributable to the Net Profits Interest is sold to a wholly owned subsidiary of Eastern American pursuant to the Gas Purchase Contract described herein.

Item 8. ***Financial Statements and Supplementary Data.***

Item 9. ***Changes in and Disagreements with Accountants on Accounting and Financial Disclosure.***

None.

Item 9A. Controls and Procedures

Evaluation of Disclosure Controls and Procedures

The Trustee maintains disclosure controls and procedures designed to ensure that information required to be disclosed by the Trust in the reports that it files or submits under the Exchange Act of 1934, as amended, is recorded, processed, summarized and reported within the time periods specified in the SEC s rules and regulations. Disclosure controls and procedures include controls and procedures designed to provide reasonable assurance that information required to be disclosed by the Trust is accumulated and communicated by several parties, including without limitation, the working interest owner, Eastern American Energy Corporation (Eastern American), and the independent reserve engineer to JPMorgan Chase Bank, N.A., as Trustee of the Trust, and its employees who participate in the preparation of the Trust s periodic reports as appropriate to allow timely decisions regarding required disclosure. In addition, the Trustee is required by the Trust Agreement to engage and has engaged an independent registered public accounting firm to review the quarterly financial statements of the Trust and audit the annual financial statements of the Trust, which includes financial data provided by Eastern American.

As of December 31, 2004, the former Trustee carried out an evaluation of the former Trustee s disclosure controls and procedures, as defined under Rule 13a-15(e) and 15d-15(e) under the Securities Exchange Act. Patrick Tadie, a Vice President of The Bank of New York, has concluded that the disclosure controls and procedures are effective at the reasonable assurance level, while noting certain limitations on disclosure controls and procedures as set forth below.

Due to the contractual arrangements of (i) the Trust Agreement and (ii) the rights of the Trustee under the Conveyances regarding information furnished by Eastern American, there are certain potential weaknesses that may limit the effectiveness of disclosure controls and procedures established by the Trustee or its employees and their ability to verify the accuracy of certain financial information. The contractual limitations creating potential weaknesses in disclosure controls and procedures may be deemed to include:

Eastern American and its consolidated subsidiaries manage (i) historical operating data, including production volumes, marketing of products, operating and capital expenditures, environmental and other liabilities, the effects of regulatory changes and the number of producing wells and acreage, (ii) plans for future operating and capital expenditures and (iii) geological data relating to reserves. While the Trustee requests material information for use in periodic reports as part of its disclosure controls and procedures, the Trustee does not manage this information, and relies to the extent considered reasonable on Eastern American to provide accurate and timely information when requested for use in the Trust s reports.

Under the terms of the Trust Agreement, the Trustee is entitled to, and in fact does, rely upon in good faith, the independent reserve engineer, as an expert with respect to the annual reserve report, which includes projected production, operating expenses and capital expenses. Other than reviewing the financial and other information provided to the Trust by Eastern American on a quarterly basis, the Trustee makes no independent or direct verification of this financial or other information. While the Trustee has no reason to believe its reliance upon this expert is unreasonable, this reliance on an expert and restricted access to information may be viewed as a weakness.

The Trustee does not intend to expand its responsibilities beyond those permitted or required by the Trust Agreement and those required under applicable law.

Changes in Internal Controls

As described elsewhere herein, The Bank of New York served as Trustee through December 31, 2004, and effective January 1, 2005, JPMorgan Chase Bank, N.A. was appointed successor Trustee. The evaluation described above of the disclosure controls and procedures as of December 31, 2004 was conducted by an officer of The Bank of New York. To the knowledge of the Trustee, during the three-month period ended December 31, 2004, there has not been any changes in the Company s internal control over financial reporting, as such term is defined in Rules 13a-15(f) and 15d-15(f) under the Exchange Act that has materially affected, or is reasonably likely to materially affect, the Company s internal control over financial reporting. The Trustee notes for purposes of clarification that it has no authority over, and makes no statement concerning, the internal controls of Eastern American.

Status of Management s Report on Internal Control over Financial Reporting

The Sarbanes-Oxley Act of 2002 (the Act) imposed many requirements regarding corporate governance and financial reporting. One requirement under section 404 of the Act, beginning with this annual report, is for management to report on the Trust s internal control over financial reporting as of December 31, 2004 and for the Trust s independent registered public accounting firm to attest to the report. In November 2004 the SEC issued an exemptive order providing a 45-day extension for the filing of these reports, and the Trust intends to include the reports in an amended Form 10-K expected to be filed in April 2005. Although management has not identified any material weakness in the internal control over financial reporting based on the testing performed to date, material weaknesses or deficiences may still be identified.

Limitations on the Effectiveness of Controls

The Trustee does not expect that the Trust s disclosure controls and procedures or the Trust s internal control over financial reporting will prevent all errors and all fraud. A registrant s internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A registrant s internal control over financial reporting includes those policies and procedures that (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the registrant; (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the registrant are being made only in accordance with authorizations of management and directors of the registrant; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the registrant s assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

Further, the design of disclosure controls and procedures and internal control over financial reporting must reflect the fact that there are resource constraints, and the benefits of controls must be considered relative to their costs. Because of the inherent limitations in all control systems, no evaluation of controls can provide absolute assurance that all control issues and instances of fraud, if any, have been detected.

Item 9B. ***Other Information.***

During the fourth quarter of 2004, the Trust issued a press release dated November 9, 2004, a copy of which is filed as Exhibit 99.1 hereto, which was inadvertently not filed under Form 8-K.

PART III

Item 10. ***Directors and Executive Officers of the Registrant.***

The Trust has no directors or executive officers. The Trustee is a corporate trustee which may be removed by the affirmative vote of holders of a majority of the Trust Units then outstanding at a meeting of the Unitholders of the Trust at which a quorum is present. The Trust is not required to and does not hold annual meetings of the Unitholders.

The Trust also does not have an audit committee or body serving a similar function, and does not have an audit committee financial expert . The Trust has not adopted a code of ethics, as the Trust has no directors, officers, or employees. The Trust has not adopted a process by which Unitholders may communicate with Board Members, as the Trust has no board members or persons fulfilling a similar function. Unitholders may contact the Trustee at the following address: JPMorgan Chase Bank, N.A., Trustee Institutional Trust Services, 700 Lavaca, Austin, Texas 78701.

Item 11. ***Executive Compensation.***

The Trust has no officers or directors, and is administered by the Trustee. For the years ended December 31, 2004, 2003 and 2002, The Bank of New York as Trustee received $45,000 annually, as Trustee fees and $650,805, $491,803 and $263,713, respectively, as reimbursement of legal, accounting, and other professional expenses for such services. Effective January 1, 2005, the annual Trustee fee increased to $108,000.

Item 12. ***Security Ownership of Certain Beneficial Owners and Management.***

(a) Security Ownership of Certain Beneficial Owners.

Based on filings with the Securities and Exchange Commission, the Trust is not aware of any person owning beneficially more than five percent of the Units as of March 1, 2005.

(b) Security Ownership of Management.

Not applicable.

(c) Changes in Control.

The Trust knows of no arrangements, including the pledge of securities of the Trust, the operation of which may at a subsequent date result in a change in control of the Trust.

(d) Securities authorized for issuance under equity compensation plans.

The Trust has no equity compensation plans.

Item 13. ***Certain Relationships and Related Transactions.***

None.

Item 14. ***Principal Accounting Fees and Services***

Audit Fees

The fees, including expenses, PricewaterhouseCoopers LLP billed the Trust for each of the last two fiscal years for professional services rendered in connection with the audits of the Trust s annual financial statements and review of the Trust quarterly interim financial statements were $69,575 in 2004 and $71,962 in 2003.

Audit-Related Fees

PricewaterhouseCoopers LLP did not bill the Trust any additional fees in the last two fiscal years for assurance and related services that are reasonably related to the performance of the audit or review of the Trust s Financial Statements.

Tax Fees

The fees, including expenses, PricewaterhouseCoopers LLP billed the Trust for each of the last two fiscal years for compliance, tax advice, or planning were $67,417 in 2004 and $126,681 in 2003.

All Other Fees

PricewaterhouseCoopers LLP did not bill the Trust any additional fees in the last two fiscal years for products and services provided by PricewaterhouseCoopers LLP, other than services reported above.

Pre-Approval Policies

The Trust does not have an audit committee or body performing a similar function. Pre-approval of all services performed by PricewaterhouseCoopers LLP and approval of the related fees is granted by the Trustee.

PART IV

Item 15. ***Exhibits, Financial Statement Schedules.***

Financial Statements

The following financial statements are included in this Annual Report on Form 10-K on the pages indicated:

Schedules

All schedules have been omitted because they are not required, not applicable or the information required has been included elsewhere herein.

Exhibits

Except as otherwise indicated below, all exhibits, except Exhibit 31 and Exhibit 32 and 99.1, are incorporated herein by reference to the indicated exhibits to filings previously made by the registrant with the Securities and Exchange Commission. All references are to the registrant s Registration Statement on Form S-1, Registration No. 33-56336, except for Exhibit 3.1, which is incorporated by reference to the Registrant s Annual Report on Form 10-K for the year ended December 31, 1994.

Exhibit Number	
3.1	Second Amended and Restated Trust Agreement of Eastern American Natural Gas Trust
4.1	Specimen Depositary Receipt
4.2	Form of NPI Royalty Deposit Agreement
10.1	Form of Conveyance
10.2	Form of Term NPI Conveyance
10.3	Form of Gas Purchase Contract between Eastern American Energy Corporation, Eastern American Marketing Corporation and Eastern American Natural Gas Trust
10.4	Form of Conveyance of Production Payment/Assignment of Production from Eastern American Natural Gas Trust to Eastern American Marketing Corporation
10.5	Form of Assignment and Standby Performance Agreement
31	Rule 13a-14(a)/15d-14(a) Certifications
32	Section 1350 Certifications
99.1	Press Release issued November 9, 2004

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized on this 28th day of March, 2005.

EASTERN AMERICAN NATURAL GAS TRUST

By:	JPMorgan Chase Bank, N.A., Trustee
By:	/s/ Mike Ulrich
Name:	Mike Ulrich
Title:	Senior Vice President

The Registrant, Eastern American Natural Gas Trust, has no principal executive officer, principal financial officer, controller or principal accounting officer, board of directors or persons performing similar functions. Accordingly, no additional signatures are available and none have been provided.

[Ryder Scott Company, Independent Petroleum Engineers Letterhead]

February 10, 2005

Eastern American Natural Gas Trust

The Bank of New York

2 North LaSalle Street, Suite 1020

Chicago, Illinois 60602

Gentlemen:

Pursuant to your request, we present below estimates of the net proved reserves attributable to the interests of the Eastern American Natural Gas Trust (Trust) as of December 31, 2004. The Trust is a grantor trust formed to hold interests in certain domestic oil and gas properties owned by Eastern American Energy Corporation (EAEC), a wholly owned subsidiary of Energy Corporation of America (ECA). The interests conveyed to the Trust consist of a net profits interest derived from working and royalty interests in numerous properties. The Net Profits Interest consists of (1) a life-of-properties interest (Royalty NPI) and (2) a term interest (Term NPI). The properties included in the Trust are located in the states of Pennsylvania and West Virginia.

The estimated reserve quantities and future income quantities presented in this report are related to a large extent to hydrocarbon prices. Hydrocarbon prices in effect at December 31, 2004 were used in the preparation of this report as required by Securities and Exchange Commission (SEC) and Financial Accounting Standards Bulletin No. 69 (FASB 69) guidelines; however, actual future prices may vary significantly from December 31, 2004 prices for reasons discussed in more detail in other sections of this report. Therefore, quantities of reserves actually recovered and quantities of income actually received may differ significantly from the estimated quantities presented in this report.

	As of December 31, 2004		
	Gas (MMCF)	Estimated Future Net Cash Inflows (M$)	Present Value At 10% (M$)
<u>Proved Net Developed</u>			
Royalty NPI	11,456	91,886	38,406
Term NPI	6,702	53,758	37,790
Total	18,158	145,644	76,196

Reserve quantities are calculated differently for a Net Profits Interest because such interests do not entitle the Trust to a specific quantity of oil or gas but to 90 percent of the Net Proceeds derived therefrom beginning on January 1, 2005 for natural gas. Accordingly, there is no precise method of allocating estimates of the quantities of proved reserves attributable to the Net Profits Interest between the interest held by the Trust and the interests to be retained by EAEC. For purposes of this presentation, the proved reserves attributable to the Net Profits Interests have been proportionately reduced to reflect the future estimated costs and expenses deducted in the calculation of Net Proceeds with respect to the Net Profits Interests. Accordingly, the reserves presented for the Net Profits Interest reflect quantities of gas that are free of future costs or expenses based on the price and cost assumptions utilized in this report. The allocation of proved reserves of the Net Profits Interest between the Trust and EAEC will vary in the future as relative estimates of future gross revenues and future net incomes vary. Furthermore, EAEC requested that for purposes of our report the Royalty NPI be calculated beyond the Liquidation Date of May 15, 2013, even though by the terms of the Trust Agreement the Royalty NPI will be sold by the Trustee on or about this date and a liquidating distribution of the sales proceeds from such sale would be made to holders of Trust Units. The Trust Agreement provides that the Term NPI entitles the Trust to receive the net proceeds from the gas produced from the properties burdened by the Term NPI until the earlier of May 15, 2013 or until such time as 41,683 MMCF of gas has been produced. For purposes of this report, the Term NPI was limited to May 15, 2013.

All gas volumes are sales gas expressed in MMCF at the pressure and temperature bases of the area where the gas reserves are located. The estimated future net cash inflows are described later in this report.

The proved reserves presented in this report comply with the Securities and Exchange Commission s Regulation S-X Part 210.4-10 Sec. (a) as clarified by subsequent Commission Staff Accounting Bulletins, and are based on the following definitions and criteria:

Proved reserves of crude oil, natural gas, or natural gas liquids are estimated quantities that geological and engineering data demonstrate with reasonable certainty to be recoverable in the future from known reservoirs under existing conditions. Reservoirs are considered proved if economic producibility is supported by actual production or formation tests. In certain instances, proved reserves may be assigned on the basis of a combination of core analysis and electrical and other type logs which indicate the reservoirs are analogous to reservoirs in the same field which are producing or have demonstrated the ability to produce on a formation test. The area of a reservoir considered proved includes (1) that portion delineated by drilling and defined by fluid contacts, if any, and (2) the adjoining portions not yet drilled that can be reasonably judged as economically productive on the basis of available geological and engineering data. In the absence of data on fluid contacts, the lowest known structural occurrence of hydrocarbons controls the lower proved limit of the reservoir. Proved reserves are estimates of hydrocarbons to be recovered from a given date forward. They may be revised as hydrocarbons are produced and additional data becomes available. Proved natural gas reserves consist of non-associated, associated and dissolved gas. An appropriate reduction in gas reserves has been made for the expected removal of natural gas liquids, for lease and plant fuel, and for the exclusion of non-hydrocarbon gases if they occur in significant quantities.

Reserves that can be produced economically through the application of improved recovery techniques are included in the proved classification when these qualifications are met: (1) successful testing by a pilot project or the operation of an installed program in the reservoir provides support for the engineering analysis on which the project or program was based, and (2) it is reasonably certain the project will proceed. Improved recovery includes all methods for supplementing natural reservoir forces and energy, or otherwise increasing ultimate recovery from a reservoir, including (1) pressure maintenance, (2) cycling, and (3) secondary recovery in its original sense. Improved recovery also includes the enhanced recovery methods of thermal, chemical flooding, and the use of miscible and immiscible displacement fluids.

Estimates of proved reserves do not include crude oil, natural gas, or natural gas liquids being held in underground or surface storage.

(i) developed reserves which are those proved reserves reasonably expected to be recovered through existing wells with existing equipment and operating methods, including (a) developed producing reserves which are those proved developed reserves reasonably expected to be produced from existing completion intervals now open for production in existing wells, and (b) developed non-producing reserves which are those proved developed reserves which exist behind the casing of existing wells which are reasonably expected to be produced through these wells in the predictable future where the cost of making such hydrocarbons available for production should be relatively small compared to the cost of a new well; and

(ii) undeveloped reserves which are those proved reserves reasonably expected to be recovered from new wells on undrilled acreage, from existing wells where a relatively large expenditure is required and from acreage for which an application of fluid injection or other improved recovery technique is contemplated where the technique has been proved effective by actual tests in the area in the same reservoir. Reserves from undrilled acreage are limited to those drilling units offsetting productive units that are reasonably certain of production when drilled. Proved reserves for other undrilled units are included only where it can be demonstrated with reasonable certainty that there is continuity of production from the existing productive formation.

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In accordance with the requirements of FASB 69, estimates of future cash inflows, future costs and future net cash inflows before income tax, as well as estimated reserve quantities, as of December 31, 2004 from this report are presented in the following table:

	As of December 31, 2004		
	Royalty NPI	**Term NPI**	**Totals**
Total Proved			
Future Cash Inflows (M$)	91,886	53,758	145,644
Future Costs			
Production (M$)	0	0	0
Development (M$)	0	0	0
Total Costs (M$)	0	0	0
Future Net Cash Inflows			
Before Income Tax (M$)	91,886	53,758	145,644
Present Value at 10%			
Before Income Tax (M$)	38,406	37,790	76,196

	As of December 31, 2004		
	Royalty NPI	**Term NPI**	**Totals**
Proved Net Developed Reserves			
Gas (MMCF)	11,456	6,702	18,158
Proved Net Undeveloped Reserves			
Gas (MMCF)	0	0	0
Total Proved Net Reserves			
Gas (MMCF)	11,456	6,702	18,158

For Net Profits Interest, the future cash inflows are, as described previously, after consideration of future costs or expenses based on the price and cost assumptions utilized in this report. Therefore, the future cash inflows are the same as the future net cash inflows. The effects of depreciation, depletion and federal income taxes have not been taken into account in estimating future net cash inflows.

EAEC furnished us gas prices in effect at December 31, 2004 and with its forecasts of future gas prices which take into account Securities and Exchange Commission guidelines, current market prices, contract prices and fixed and determinable price escalations where applicable. In accordance with Securities and Exchange Commission guidelines, the future gas prices used in this report make no allowances for future gas price increases or decreases which may occur as a result of inflation nor do they account for seasonal variations in gas prices which are likely to cause future yearly average gas prices to be somewhat higher than December gas prices. In those cases where contract market-out has occurred, the current market price was held constant to depletion of the reserves. In those cases where market-out has not occurred, contract gas prices including fixed and determinable escalations, exclusive of inflation adjustments, were used until the contract expired and then reduced to the current market price for similar gas in the area and held at this reduced price to depletion of the reserves.

This report utilized the terms of the gas contract between Eastern Marketing Corporation (a wholly owned subsidiary of EAEC) and the Trust. Gas price is to be determined by a weighted price consisting of two components during a primary term defined to begin on January 1, 1993 and end December 31, 1999. The first component is the Fixed price which has been defined as $2.66 per Mcf beginning January 1, 1993. This price escalates 5 percent per year on January 1 of each year during the primary term beginning in 1994. The second component is the Variable price which for any quarter is equal to the Henry Hub Average Spot Price (as defined) per MMBtu, plus $0.30 per MMBtu, multiplied by 110 percent to effect a Btu adjustment. The Henry Hub Average Spot Price is defined as the price per MMBtu determined for any calendar quarter as the average price of the three months in such quarter where each month s price is equal to the average of (i) the final settlement prices per MMBtu for Henry Hub Gas Futures Contracts (as defined), as reported in the Wall Street Journal, for such contracts which expired in each of the five months prior to each month of such quarter, (ii) the final settlement price per MMBtu for Henry Hub Gas Futures Contracts, as reported in the Wall Street Journal, for such contracts which expire during such month and (iii) the closing settlement prices per MMBtu of Henry Hub Gas Futures Contracts for such month, as reported in the Wall Street Journal, for such contracts which expire in each of the six months following such month. A Henry Hub Gas Futures Contract is defined as a gas futures contract for gas to be delivered to the Henry Hub which is traded on the New York Mercantile Exchange. The weighted average price is determined by giving the Fixed price a 66 2/3 percent weighting and the variable price a 33 1/3 percent weighting.

Since the primary term is complete, the purchase price under the gas contract will be equal to the Variable price. EAEC computed the Variable price under the gas contract as of December 31, 2004 as $8.021 per Mcf, utilizing $6.992 as the Henry Hub Average Spot Price computed in accordance with the gas contract.

Operating costs for the leases and wells in this report were supplied by EAEC and include only costs defined as applicable under terms of the Trust. The current operating costs were held constant throughout the life of the properties. This study does not consider the salvage value of the lease equipment or the abandonment cost.

No deduction was made for indirect costs such as general administration and overhead expenses, loan repayments, interest expenses, and exploration and development prepayments. No attempt has been made to quantify or otherwise account for any accumulated gas production imbalances that may exist.

Our reserve estimates are based upon a study of the properties in which the Trust has interests; however, we have not made any field examination of the properties. No consideration was given in this report to potential environmental liabilities which may exist nor were any costs included for potential liability to restore and clean up damages, in any, caused by past operating practices. EAEC informed us that it has furnished us all of the accounts, records, geological and engineering data and reports and other data as were required for our investigation. The ownership interests, terms of the Trust, prices, taxes, and other factual data furnished to us in connection with our investigation were accepted as represented. The estimates presented in this report are based on data available through July, 2004.

At the time of formation of the Trust, EAEC assigned The Trust an interest in 65 undeveloped locations. During the period 1993 through 1998, EAEC has completed it s drilling obligation. A total of 59 wells were drilled over this period. Two wells were not drilled due to title failure and four wells were not drilled due to short spacing. Reserves and projections of future production are included for the four locations which were not drilled due to short spacing.

The reserves included in this report are estimates only and should not be construed as being exact quantities. They may or may not be actually recovered. Moreover, estimates of proved reserves may increase or decrease as a result of future operations of EAEC. Moreover, due to the nature of the Net Profits Interest, a change in the future costs, or prices different from those projected herein may result in a change in the computed reserves and the Net Proceeds to the Trust even if there are no revisions or additions to the gross reserves attributed to the property.

The future production rates from properties now on production may be more or less than estimated because of changes in market demand or allowables set by regulatory bodies. Properties which are not currently producing may start producing earlier or later than anticipated in our estimates of their future production rates.

The future prices received by EAEC for the sale of its production may be higher or lower than the prices used in this report as described above, and the operating costs and other costs relating to such production may also increase or decrease from existing levels; however, such possible changes in prices and costs were, in accordance with rules adopted by the Securities and Exchange Commission, omitted from consideration in preparing this report.

At the request of EAEC, we have included the following table which summarizes the total net reserves estimates from combined interest of EAEC and the Trust in theUnderlying Properties:

Estimated Net Reserve Data

Certain Combined Leasehold Interests of

Eastern America Energy Corporation

And The Trust

As of December 31, 2004

SEC Parameters

	Proved Developed	Proved Undeveloped	Total Proved
Net Remaining Reserves			
Gas-MMCF	36,328	0	36,628

The estimated future net income associated with the foregoing volumes and the 10 percent discounted estimated future net income was $244,990,453 and $99,361,100, respectively. This evaluation utilizes the same price and cost assumptions that were utilized for evaluating the Trust and discussed earlier in the letter. The properties which are included in the Term NPI were allowed to run for their full economic life in this evaluation.

Neither Ryder Scott Company nor any of its employees has any interest in the subject properties and neither the employment to make this study nor the compensation is contingent on our estimates of reserves and future cash inflows for the subject properties.

Very truly yours,

RYDER SCOTT COMPANY, L.P.

Larry T. Nelms P. E.
Managing Senior Vice President

LTN:ph

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FINANCIAL STATEMENTS

as of December 31, 2004 and 2003

and for the years ended

December 31, 2004, 2003 and 2002

2003 Compared with 2002

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Unitholders and JPMorgan Chase Bank, N.A.,

As Trustee for Eastern American Natural Gas Trust:

We have audited the accompanying statements of assets, liabilities and trust corpus of Eastern American Natural Gas Trust (the Trust) as of December 31, 2004 and 2003, and the related statements of distributable income, and changes in trust corpus for each of the three years in the period ended December 31, 2004. These financial statements are the responsibility of the Trustee. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by the Trustee, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

As described in Note 2, these financial statements were prepared on the basis of accounting prescribed by the Trust Agreement, which is a comprehensive basis of accounting other than accounting principles generally accepted in the United States of America.

In our opinion, the financial statements referred to above present fairly, in all material respects, the financial position of the Trust at December 31, 2004 and 2003, and the distributable income and changes in trust corpus for each of the three years in the period ended December 31, 2004, on the basis of accounting described in Note 2.

/s/ PricewaterhouseCoopers LLP

Pittsburgh, Pennsylvania

March 28, 2005

EASTERN AMERICAN NATURAL GAS TRUST

STATEMENTS OF ASSETS, LIABILITIES AND TRUST CORPUS

as of December 31, 2004 and 2003

	2004	2003
Assets:		
Cash	$ 185,752	$ 115,205
Net Proceeds Receivable	3,989,827	2,678,769
Net Profits Interests in Gas Properties	93,162,180	93,162,180
Accumulated Amortization	(62,337,672)	(58,519,514)
Total Assets	$ 35,000,087	$ 37,436,640
Liabilities and Trust Corpus:		
Trust General and Administrative Expenses Payable	$ 220,596	$ 161,772
Distributions Payable	3,639,983	2,417,202
Trust Corpus (5,900,000 Trust Units authorized and outstanding)	31,139,508	34,857,666
Total Liabilities and Trust Corpus	$ 35,000,087	$ 37,436,640

The accompanying notes are an integral part of these financial statements.

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EASTERN AMERICAN NATURAL GAS TRUST

STATEMENTS OF DISTRIBUTABLE INCOME

for the years ended

December 31, 2004, 2003 and 2002

	2004	2003	2002
Royalty Income	$ 14,449,208	$ 13,177,510	$ 9,024,646
Operating Expenses:			
Taxes on production and property	989,430	897,881	613,115
Operating cost charges	519,228	510,032	501,738
Total Operating Expenses	1,508,658	1,407,913	1,114,853
Net Proceeds to the Trust	12,940,550	11,769,597	7,909,793
General and Administrative Expenses	(1,002,397)	(833,027)	(594,921)
Interest Income	1,489	953	1,810
Cash Proceeds on Sale of Net Profits Interests	80,205	10,293	492,043
Distributable Income	12,019,847	10,947,816	7,808,725
Cash Reserve	(100,000)	(215,000)	0
Distribution Amount	$ 11,919,847	$ 10,732,816	$ 7,808,725
Distributable Income Per Unit (5,900,000 Units authorized and outstanding)	$ 2.0373	$ 1.8556	$ 1.3235
Distribution Amount Per Unit (5,900,000 units authorized and outstanding)	$ 2.0203	$ 1.8191	$ 1.3235

The accompanying notes are an integral part of these financial statements.

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EASTERN AMERICAN NATURAL GAS TRUST

STATEMENTS OF CHANGES IN TRUST CORPUS

for the years ended

December 31, 2004, 2003 and 2002

	2004	2003	2002
Trust Corpus, Beginning of Period	$ 34,857,666	$ 38,695,799	$ 43,169,981
Distributable Income	12,019,847	10,947,816	7,808,725
Distributions Paid or Payable to Unitholders	(11,919,847)	(10,732,816)	(7,808,725)
Amortization of Net Profits Interests in Gas Properties	(3,818,158)	(4,053,133)	(4,474,182)
Trust Corpus, End of Period	$ 31,139,508	$ 34,857,666	$ 38,695,799

The accompanying notes are an integral part of these financial statements.

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EASTERN AMERICAN NATURAL GAS TRUST

NOTES TO FINANCIAL STATEMENTS

1. <u>Organization of the Trust:</u>

The Eastern American Natural Gas Trust (the Trust) was formed under the Delaware Business Trust Act pursuant to a Trust Agreement (the Trust Agreement) among Eastern American Energy Corporation (Eastern American), as grantor, Bank of Montreal Trust Company, as Trustee, and Wilmington Trust Company, as Delaware Trustee (the Delaware Trustee). Effective May 8, 2000, The Bank of New York acquired the corporate trust business of The Bank of Montreal Trust Company. As a result, The Bank of New York served as Trustee (the Trustee). On November 20, 2004, the holders of a majority of the Trust Units voting at a special meeting approved the resignation of The Bank of New York as trustee and depository of the Trust and the appointment of JPMorgan Chase Bank, N.A. as successor trustee of the Trust. The appointment of JPMorgan Chase Bank, N.A. as successor trustee became effective as of January 1, 2005. Consequently, references herein to the Trustee mean JPMorgan Chase Bank, N.A. as successor trustee, on and after January 1, 2005. References to the Trustee at any time prior to January 1, 2005 mean The Bank of New York as trustee. Effective January 1, 2005, the transfer agent for the Trust is Bondholder Communications.

The purpose of the Trust is to acquire and hold net profits interests owned by Eastern American in 650 producing gas wells and 65 proved development well locations in West Virginia and Pennsylvania (the Underlying Properties). The Underlying Properties are operated by Eastern American. The Net Profits Interests (the Net Profits Interests) consist of a Royalty interest in 322 wells and a Term interest in the remaining wells and locations. Eastern American drilled 59 of the 65 development wells.

The Royalty NPI is not limited in term or amount. Under the Trust Agreement, the Trustee is directed to sell all remaining Royalty NPI after May 15, 2012 and prior to May 15, 2013, and net proceeds from selling such Royalty NPI will be distributed to Unitholders on the first quarterly payment date following the receipt of such proceeds by the Trust. The Term NPI will expire on the earlier of May 15, 2013 or such time as 41,683 MMcf of gas has been produced which is attributable to Eastern American s net revenue interests in the properties burdened by the Term NPI. As of December 31, 2004, 20,706 MMcf of such gas had been produced.

Eastern American can sell the Underlying Properties, subject to and burdened by the Net Profits Interests, without the consent of the Trustee or the Unitholders. In limited circumstances, Eastern American also can transfer the Underlying Properties and require the Trust to release the NPI burdening that property, without the consent of the Trustee or Unitholders, subject to payment to the Trust of the fair value of the interest released. In addition, any abandonment of a well included in the Underlying Properties or the Development Wells will extinguish that portion of the Net Profits Interests that relate to such well.

Four (4) of the remaining six (6) development wells were closely offset by third parties. Since the wells drilled by the third parties were within 1,000 feet of these development wells, Eastern American had a disagreement with the Trust over Eastern American s obligation to drill these closely offset development wells. The Trust has agreed that, in lieu of drilling these closely offset development wells Eastern American can provide the Trust, on an annual basis commencing on April 1, 1997, and over the remaining life of the Trust, a volume of gas which is equal to the projected volumes of the wells as if they had been drilled. These volumes have been estimated by the Ryder Scott Company.

The two (2) remaining development wells were not drilled because Eastern American was unable to cure various title defects associated with these wells. Eastern American advised the Trust that it made a diligent effort to cure title but was unsuccessful. In West Virginia, an oil and gas well cannot be drilled unless a full and complete 100% leasehold interest is first obtained. Drilling an oil and gas well without obtaining the entire leasehold estate would expose the oil and gas operator and the Trust to a possible suit for trespass. Pursuant to the Term Net Profits Interest Conveyance, if the state of title to the drill site to any development well renders such property undrillable in the good faith opinion of Eastern American under the Reasonably Prudent Operator Standard then such drill site(s) shall be construed as a development well(s). Consequently, Eastern American has fulfilled its commitment to the Trust to drill the required number of development wells.

On March 15, 1993, 5,900,000 depositary units were issued in a public offering at an initial public offering price of $20.50 per depositary unit. Each depositary unit consists of beneficial ownership of one unit of beneficial interest (Trust Unit) in the Trust and a $20 face amount beneficial ownership interest in a $1,000 face amount zero coupon

United States Treasury Obligation (Treasury Obligation) maturing on May 15, 2013. Of the net proceeds from such offering, $27,787,820 was used to purchase $118,000,000 in face amount of Treasury Obligations and $93,162,180 was paid to Eastern American in consideration for the conveyance of the Net Profits Interests to the Trust. The Trust acquired the Net Profits Interests effective as of January 1, 1993. The Treasury Obligations are directly owned by the Unitholders and are not part of the Trust Corpus. The Treasury Obligations are on deposit with the Trustee pursuant to the Deposit Agreement.

The Net Profits Interests are passive in nature, and neither the Trustee nor the Delaware Trustee has management control or authority over, nor any responsibility relating to, the operation of the properties subject to the Net Profits Interests. The Trust Agreement provides, among other things, that the Trust shall not engage in any business or commercial activity or acquire any asset other than the Net Profits Interests initially conveyed to the Trust; the Trustee may establish a reserve for payment of any liability which is contingent, uncertain in amount or that is not currently due and payable; the Trustee is authorized to borrow funds required to pay liabilities of the Trust, provided that such borrowings are repaid in full prior to further distributions to Unitholders; and the Trustee will make quarterly cash distributions to Unitholders from funds of the Trust.

2. Significant Accounting Policies:

The following is a summary of the significant accounting policies followed by the Trust.

Basis of Accounting:

The financial statements of the Trust differ from financial statements prepared in accordance with accounting principles generally accepted in the United States of America due to the following; i) certain cash reserves may be established for contingencies which were not accrued in the financial statements; ii) amortization of the Net Profits Interests in gas properties is charged directly to Trust Corpus; and iii) the sale of the Net Profits Interests is reflected in the Statements of Distributable Income as cash proceeds to the Trust.

Cash:

Cash consists of highly liquid instruments with maturities at the time of acquisition of three months or less.

Net Profits Interests in Gas Properties:

The Net Profits Interests in gas properties are periodically assessed to determine whether their net capitalized cost is impaired. The Trust will determine if a writedown is necessary to its investment in the Net Profits Interests in gas properties to the extent that total capitalized costs, less accumulated amortization, exceed undiscounted future net revenues attributable to proved gas reserves of the Underlying Properties. The Trust will then provide a writedown to the extent that the net capitalized costs exceed the discounted future net revenues attributable to proved gas reserves of the Underlying Properties. Any such writedown would not reduce distributable income, although it would reduce Trust Corpus.

Significant dispositions or abandonment of the Underlying Properties are charged to Net Profits Interests and the Trust Corpus.

Amortization of the Net Profits Interests in gas properties is calculated on a units-of-production basis, whereby the Trust s cost basis in the properties is divided by total Trust proved reserves to derive an amortization rate per reserve unit. Such amortization does not reduce distributable income, rather it is charged directly to Trust Corpus. Revisions to estimated future units-of-production are treated on a prospective basis beginning on the date significant revisions are known.

The conveyance of the Royalty and Term Interests to the Trust was accounted for as a purchase transaction. The $93,162,180 reflected in the Statement of Assets, Liabilities and Trust Corpus as Net Profits Interests represents 5,900,000 Trust Units valued at $20.50 per depository unit less the $27,787,820 paid for Treasury obligations. The carrying value of the Trust s investment in the Royalty Interests is not necessarily indicative of the fair value of such Royalty Interests.

Revenues and Expenses:

The Trust serves as a pass-through entity, with items of depletion, interest income and expense, and income tax attributes being based upon the status and election of the Unitholders. Thus, the Statements of Distributable Income purport to show distributable income, defined as Trust income available for distribution to Unitholders before application of those Unitholders additional expenses, if any, for depletion, interest income and expense, and income taxes.

The Trust uses the accrual basis to recognize revenue, with royalty income recorded as reserves are extracted from the Underlying Properties and sold. Expenses are also recognized on an accrual basis. Operating expenses which include taxes on production and operating cost charges are recognized as incurred pursuant to the Conveyances on a per well production basis. The payment provisions of the gas purchase contract between the Trust and Eastern Marketing Corporation require payment with respect to gas production for a calendar quarter to be made to the Trust on or before the tenth day of the third month following such quarter.

Use of Estimates in the Preparation of Financial Statements:

The preparation of financial statements requires the Trust to make estimates and assumptions that affect the reported amounts of assets and liabilities and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates.

Segment Information:

In 1998, the Trust adopted SFAS 131, Disclosure about Segments of an Enterprise and Related Information. The Trust s sole activity is earning royalty income from gas properties and, consequently, the Trust has only one operating segment, net profits interests in gas properties. Substantially all of the Trust s net profits interests are located in the Appalachian region.

3. Income Taxes:

Tax counsel to Eastern American advised Eastern American at the time of formation that, under then current tax laws, the Trust would be classified as a grantor trust for federal and state income tax purposes and, therefore, would not be subject to taxation at the Trust level. The Trust continues to be tax exempt. Accordingly, no provision for federal or state income taxes has been made. However, the opinion of tax counsel is not binding on taxing authorities.

The Unitholders are considered, for income tax purposes, to own the Trust s income and principal as though no trust were in existence. Thus, the taxable year for reporting a Unitholder s share of the Trust income, expense and credits are controlled by the Unitholder s taxable year and method of accounting, not the taxable year and method of accounting employed by the Trust.

4. Distributions to Unitholders:

The Trustee determines for each quarter the amount available for distribution to the Unitholders. Such amount will be equal to the excess, if any, of the cash received by the Trust, on or before the tenth day of the third month following the end of each calendar quarter ending prior to the dissolution of the Trust, from the Net Profits Interests then held by the Trust attributable to production during such quarter, plus, with certain exceptions, any other cash receipts of the Trust during such quarter, over the liabilities of the Trust paid during such quarter, subject to adjustments for changes made by the Trustee during such quarter in any cash reserves established at the discretion of the Trustee for the payment of contingent or future obligations of the Trust. Cash received by the Trustee in a particular quarter from the Net Profits Interests will reflect actual gas production for a portion of such quarter and a production estimate for the remainder of such quarter, such estimate to be adjusted to actual production in the following quarter. In accordance with the Trust Agreement and Delaware law, Unitholders should be shielded from direct liability for any environmental liabilities. However, costs and expenses incurred by Eastern American for certain Capital Costs associated with environmental liabilities arising after the effective date of the Conveyances would reduce Net Proceeds, and would therefore be borne, in part, by the Unitholders.

Net Proceeds Receivable included in the Statements of Assets, Liabilities and Trust Corpus as of December 31, 2004 are expected to be received by the Trust and distributed to the Unitholders on March 16, 2005. The December 31, 2003 Net Proceeds Receivable were received and distributed by the Trust on March 15, 2004.

5. Related Party Transactions:

The Trust is responsible for paying all legal, accounting, engineering and stock exchange fees, printing costs and other administrative expenses incurred at the direction of the Trustee. The total of all Trustee fees and Trust administrative expenses was $695,805 for the year ended December 31, 2004, $536,803 for the year ended December 31, 2003, and $308,713 for the year ended December 31, 2002. In accordance with the Trust Agreement, the Trustee pays Eastern American an annual fee which increases by 3.5% per year, payable quarterly, to reimburse Eastern American for overhead expenses. The initial fee at the inception of the Trust was $210,000. The Trustee paid Eastern American $306,592, $296,224 and $286,208 for overhead expenses for 2004, 2003 and 2002 respectively. Operating cost charges included in the Statements of Distributable Income are paid to Eastern American.

Gas production attributable to the Net Profits Interests is purchased from the Trust by Eastern Marketing Corporation (Eastern Marketing), a wholly owned subsidiary of Eastern American, pursuant to a Gas Purchase Contract which effectively commenced as of January 1, 1993 and expires upon the termination of the Trust.

Pursuant to the Gas Purchase Contract, Eastern Marketing is obligated to purchase such gas production at a purchase price per Mcf equal to the greater of the Index Price, as defined below, or a Floor Price, for gas produced in any quarter during the Primary Term, which ended December 31, 1999. Effective January 1, 2000, Eastern Marketing is obligated to purchase such gas production at a purchase price per Mcf equal to the Index Price for gas produced in any quarter after the Primary Term.

The Index Price for any quarter subsequent to the Primary Term, which expired December 31, 1999, is determined solely by reference to the Variable Price component. The Variable Price for any quarter is equal to the Henry Hub Average Spot Price (as defined) per MMBtu plus $0.30 per MMBtu, multiplied by 110% to effect a fixed adjustment for Btu content. The Henry Hub Average Spot Price is defined as the price per MMBtu determined for any calendar quarter equal to the price obtained with respect to each of the three months in such quarter, in the manner specified below, and then taking the average of the prices determined for each of such three months. The price determined for any month of such quarter is equal to the average of (i) the final settlement prices per MMBtu for Henry Hub Gas Futures Contracts (as defined), as reported in *The Wall Street Journal,* for such contracts which expired in each of the five months prior to such month, (ii) the final settlement price per MMBtu for Henry Hub Gas Futures Contracts, as reported in *The Wall Street Journal,* for such contracts which expire during such month and (iii) the closing settlement prices per MMBtu of Henry Hub Gas Futures Contracts determined as of the contract settlement date for such month, as reported in *The Wall Street Journal,* for such contracts which expire in each of the six months following such month. A Henry Hub Gas Futures Contract is defined as a gas futures contract for gas to be delivered to the Henry Hub which is traded on the New York Mercantile Exchange.

Under a standby performance agreement Eastern American has agreed to make payments under the Gas Purchase Contract to the extent such payments are not made by Eastern Marketing.

6. <u>Supplemental Reserve Information (Unaudited)</u>:

Information regarding estimates of the proved gas reserves attributable to the Trust are based on reports prepared by independent petroleum engineering consultants. Such estimates were prepared in accordance with guidelines established by the Securities and Exchange Commission. Accordingly, the estimates were based on existing economic and operating conditions. Numerous uncertainties are inherent in estimating reserve volumes and values and such estimates are subject to change as additional information becomes available.

The reserves actually recovered and the timing of production of these reserves may be substantially different from the original estimates.

The standardized measure of discounted future net cash flows was determined based on reserve estimates prepared by the independent petroleum engineering consultants. Fixed gas prices were used during the Primary Term, which ended December 31, 1999. The gas prices used thereafter are based solely on the fourth quarter Variable Price component.

The reserves and revenue values for the Underlying Properties transferred to the Trust were estimated from projections of reserves and revenue values attributable to the combined Eastern American and Trust interests in these properties. Reserve quantities are calculated differently for the

Net Profits Interests because such interests do not entitle the Trust to a specific quantity of gas but to 90 percent of the Net Proceeds derived therefrom. Accordingly, there is no precise method of allocating estimates of the quantities of proved reserves between those held by the Trust and the interests to be retained by Eastern American. For purposes of this presentation, the proved reserves attributable to the Net Profits Interests have been proportionately reduced to reflect the future estimated costs and expenses deducted in the calculation of Net Proceeds with respect to the Net Profits Interests. The reserves presented for the Net Profits Interests reflect quantities of gas that are free of future costs or expenses. The allocation of proved reserves between the Trust and Eastern American will vary in the future as relative estimates of future gross revenues and future costs and expenses vary.

The royalty portion of the Net Profits Interests was calculated beyond the liquidation date of the Trust (May 15, 2013), even though the terms of the Trust Agreement require that the Royalty Net Profits Interest be sold by the Trustee on or about this date and a liquidating distribution from the sales proceeds from such sale would be made to the Unitholders. The Term Net Profits Interests was limited to the 20-year period as defined by the Trust Agreement.

The following table reconciles the change in proved reserves attributable to the Trust s share of the Net Profits Interests (NPI) from January 1, 2002 to December 31, 2004:

	Royalty NPI (MMcf)	Term NPI (MMcf)	Total NPI (MMcf)
Balance, January 1, 2002	12,904	9,841	22,745
Production	(1,034)	(1,324)	(2,357)
Revisions of previous estimates	(155)	(92)	(246)
Balance, December 31, 2002	12,025	8,609	20,634
Production	(932)	(1,229)	(2,161)
Revisions of previous estimates	201	87	288
Balance, December 31, 2003	11,294	7,467	18,761
Production	(910)	(1,158)	(2,068)
Revisions of previous estimates	1,072	393	1,464
Balance, December 31, 2004	11,456	6,702	18,158

The Trust s share of proved developed gas reserves are as follows:

	Royalty NPI (MMcf)	Term NPI (MMcf)	Total NPI (MMcf)
December 31, 2002	12,025	8,609	20,634
December 31, 2003	11,294	7,467	18,761
December 31, 2004	11,456	6,702	18,158

Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Reserves:

The following is the standardized measure of discounted future net cash flows as of December 31, 2004 (in thousands):

	Royalty NPI	Term NPI	Total NPI
Future cash inflows	$ 110,781	$ 60,830	$ 171,612
Future production taxes	(6,130)	(2,942)	(9,073)
Future production costs	(12,765)	(4,130)	(16,895)
Future net cash inflows	91,886	53,758	145,644
10% discount factor	(53,480)	(15,968)	(69,448)
Standardized measure of discounted future net cash flows	$ 38,406	$ 37,790	$ 76,196

The following is the standardized measure of discounted future net cash flows as of December 31, 2003 (in thousands):

	Royalty NPI	Term NPI	Total NPI
Future cash inflows	$ 80,951	$ 49,043	$ 129,994
Future production taxes	(4,420)	(2,333)	(6,754)
Future production costs	(11,885)	(3,967)	(15,852)
Future net cash inflows	64,646	42,743	107,389
10% discount factor	(37,289)	(13,651)	(50,940)
Standardized measure of discounted future net cash flows	$ 27,357	$ 29,092	$ 56,449

The following is the standardized measure of discounted future net cash flows as of December 31, 2002 (in thousands):

	Royalty NPI	Term NPI	Total NPI
Future cash inflows	$ 69,983	$ 44,562	$ 114,545
Future production taxes	(3,839)	(2,104)	(5,943)
Future production costs	(12,400)	(3,986)	(16,386)
Future net cash inflows	53,743	38,472	92,215
10% discount factor	(30,790)	(13,114)	(43,904)
Standardized measure of discounted future net cash flows	$ 22,953	$ 25,358	$ 48,311

Changes in Standardized Measure of Discounted Future Net Cash Flows:

The following schedule reconciles the changes during 2002, 2003 and 2004 in the standardized measure of discounted future net cash flows relating to proved reserves (in thousands):

	Royalty NPI	Term NPI	Total NPI
Standardized measure, January 1, 2002	$ 20,009	$ 22,419	$ 42,428
Net proceeds to the Trust	(4,610)	(3,300)	(7,910)
Revisions of previous estimates	(363)	(215)	(578)
Accretion of discount	2,001	2,242	4,243
Net change in price and production costs	5,650	4,054	9,704
Other	266	159	425
Standardized measure, December 31, 2002	$ 22,953	$ 25,358	$ 48,311
Net proceeds to the Trust	(7,085)	(4,684)	(11,770)
Revisions of previous estimates	1	0	1
Accretion of discount	2,295	2,536	4,831
Net change in price and production costs	7,405	4,926	12,331
Other	1,788	956	2,745
Standardized measure, December 31, 2003	$ 27,357	$ 29,092	$ 56,449
Net proceeds to the Trust	(8,164)	(4,776)	(12,941)
Revisions of previous estimates	4,498	1,649	6,148
Accretion of discount	2,736	2,909	5,645
Net change in price and production costs	12,331	7,491	19,822
Other	(352)	1,425	1,073
Standardized measure, December 31, 2004	$ 38,406	$ 37,790	$ 76,196

7. Quarterly Financial Data (Unaudited):

The following is a summary of royalty income and distributable income per unit by quarter in 2004, 2003 and 2002 (all amounts in thousands except Distributable income per unit):

2004	**Mar 31**	**June 30**	**Sept 30**	**Dec 31**	**Total**
Royalty income	$ 3,080	$ 3,492	$ 3,452	$ 4,425	$ 14,449
Distributable income	$ 2,512	$ 3,019	$ 2,849	$ 3,640	$ 12,020
Distributable income per unit	$ 0.4257	$ 0.5117	$ 0.4829	$ 0.6169	$ 2.0373

2003	**Mar 31**	**June 30**	**Sept 30**	**Dec 31**	**Total**
Royalty income	$ 2,999	$ 3,645	$ 3,521	$ 3,012	$ 13,177
Distributable income	$ 2,363	$ 3,054	$ 3,014	$ 2,517	$ 10,948
Distributable income per unit	$ 0.4005	$ 0.5175	$ 0.5109	$ 0.4266	$ 1.8556

2002	**Mar 31**	**June 30**	**Sept 30**	**Dec 31**	**Total**
Royalty income	$ 1,771	$ 2,192	$ 2,449	$ 2,612	$ 9,025
Distributable income	$ 1,663	$ 1,950	$ 2,030	$ 2,166	$ 7,809
Distributable income per unit	$ 0.2819	$ 0.3305	$ 0.3440	$ 0.3671	$ 1.3235